STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2001-679

January 7, 2003

NORTHERN UTILITIES, INC.,
Petition for Approval of the Use of
Financial Instruments as a Part of
A Hedging Program

ORDER

Welch, Chairman; Nugent and Diamond, Commissioners

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I. EXECUTIVE SUMMARY

1. Northern Utilities, Inc.’s (NU, Northern, or the Company) revised plan includes time and price triggered hedging actions (or non-actions) that are largely mechanical in operation. The plan does not anticipate that Northern will adapt its hedging behavior to, for example, changing expectations of future price levels or to increases or decreases in the likely level of variability in future market prices.

2. Northern is unwilling to agree to a hedging approach which is not mechanical in its application because it is worried about being second-guessed with resulting disallowances.

3. If the NU proposal had been in place over the last five years, volatility would have been somewhat reduced. Bills would have been lower by approximately $121.10 for the average residential customer during 2000-2001 when there was a large, unanticipated price increase but would have been higher by $68.90 for these customers in 2001-2002 when there was an unanticipated decrease in market prices. Overall, prices would have been slightly lower over this specific period, primarily because the 2000-01 increase was larger than the 2001-02 decrease.

4. We found similar results in reviewing the volatility of the oil market since 1946 and the gas market since 1974. Most years there were small increases or decreases in the price of these fuels but there were a few years when there were large increases and decreases. Generally, we would expect a significant savings from hedging only in the few years when there are significant price run-ups, such as 2000-01.

5. At its June 25, 2002 deliberations, the Commission indicated a general interest in allowing Northern to proceed with a limited hedging program like the one proposed to gain additional experience but indicated it wished the Staff to pursue a plan that also allowed for additional discretion in purchasing. The Staff and Northern were not able to work out a mutually agreeable proposal due to Northern's concerns about the regulatory uncertainty of acting under a discretionary plan.

6. At our deliberative session on December 16, 2002, we decided to go forward with Northern’s hedging plan as proposed for the Maine Division, which is also currently in effect for Northern's New Hampshire Division, with certain clarifications.

7. Given the timing of our approval, it is too late to fully implement Northern's program for the 2002-2003 hedging period. However, the Price-Triggered component can be implemented for the 2002-2003 hedging period and the Time-Triggered component should be adapted to take at least partial effect in the 2003-2004 hedge period.

8. The Commission also directs Northern to evaluate the use of alternatives or improvements, such as call options with a relatively high strike price, either in conjunction with or in place of the current plan. Based on the historic price trend analysis contained in this Report, it appears such a modification to this plan might yield greater benefits to ratepayers by mitigating sharp market price increases while preserving the opportunity to take advantage of downward market price changes.

9. We will consider Northern's actions taken in accordance with this program prudent so long as it can demonstrate that: 1) it has monitored the market and the actions of other market players, including its affiliates; 2) it has periodically reviewed the goals of its hedging program and the success in achieving those goals; and 3) it has recommended to the Commission changes in the operation of its program whenever it has concluded, based on its monitoring of the market and its review of its program, that such changes are warranted.

10. Finally, we require Northern to justify to the Commission continuation of this program if it wishes to continue to use it after the 2005-2006 hedge period.

II. OVERVIEW

A. Procedural History

On September 28, 2001, Northern filed a petition requesting approval of a natural gas hedging program that would use futures contracts as a means of reducing the volatility of the price of natural gas on behalf of its ratepayers. The Company also requested that any transaction costs incurred in the purchase of futures contracts as well as any costs of administering the program be passed through to ratepayers.

On October 4, 2001, we issued a Notice of Proceeding inviting intervention or comment from interested persons. Timely petitions to intervene from the Office of the Public Advocate (OPA) and Bangor Gas Company (BGC) were granted at the initial case and technical conference held on October 25, 2001. The Commission Staff and OPA questioned the Company about its plan at the October 25 conference.

At this conference, NU indicated that its affiliate, Bay State Gas Company (BSG or Bay State), was about to file a proposal for a Gas Cost Incentive Mechanism (GCIM) with the Massachusetts Department of Energy and Telecommunications (DTE) and that NU would be open to filing a similar petition here if the Commission preferred.

By letter dated November 9, 2001, NU filed a copy of BSG's petition to the DTE in this docket.[1]

On October 26, 2001, BGC filed comments regarding how the Commission should generally view hedging proposals filed by local natural gas distribution utilities (LDCs), and advocated that the Commission consider each LDC proposal on a case-by-case basis.

On May 31, 2002, Advisory Staff issued an Examiner's Report that recommended rejecting NU's proposed plan and made a general policy statement regarding the use of financial derivatives to hedge price fluctuations of natural gas. The basis for the Examiner's conclusion was that there did not appear to be any appreciable benefits for ratepayers, nor did there appear to be any incentive for the Company to be particularly effective in its hedging activities. The Examiner noted that NU was apparently requesting almost blanket pre-approval of its hedging activities and therefore concluded that any after-the-fact prudence review would not be sufficient to protect ratepayers if the plan were flawed in design or in execution. In its written exceptions, NU disagreed with the Examiner's characterization of its hedging plan, particularly with regard to after-the-fact prudence reviews. NU also noted that the main goal of its hedging plan was to improve the overall price stability for its ratepayers and not to obtain an "optimal" price.

The OPA also filed written exceptions to the Examiner's Report and proposed that the Company offer different pricing options (e.g. fixed, floating or capped) to its ratepayers and that it use the appropriate hedging tools to make such offerings. At its deliberations on June 25, 2002, the Commission tabled the Examiner's Report and directed the parties to develop a hedging program similar to the one proposed by NU which, among other things, allowed Northern a degree of flexibility in making individual hedging purchase decisions.

On July 19, 2002, NU filed a hedging plan with the New Hampshire Public Utilities Commission (NHPUC) that it viewed as an improvement over the plan previously filed here and invited the Advisory Staff to participate in a joint technical conference with the Company and New Hampshire Staff. The Advisory Staff participated in the joint session on August 12, 2002 by telephone. On August 15, August 22 and August 30, the Advisory Staff and the Company held teleconferences in which follow-up questions regarding the operation of the plan and the prudence protection the Company was seeking were discussed. To avoid any misunderstandings regarding the workings of the currently proposed plan or the level of prudence protection sought by NU, the Hearing Examiner sent a letter to the Company on

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[1] With its comments, Northern provided a copy of the Massachusetts DTE's December 4, 2002 order in docket D.T.E. 01-81 approving Bay State Gas Company's (BGC) proposed gas cost incentive mechanism with modifications.

September 20, 2002, stating its understanding of these elements of its proposal. The Company responded in writing on October 4, 2002.

On November 27, 2002, the Hearing Examiner issued a Supplemental Examiner's Report, describing Northern's revised hedging proposal and providing an approximation and analysis of the likely impact of the plan if it had been in place during the last few years. On December 12, 2002, the Company filed comments clarifying certain aspects of the implementation and operation of its plan. We concluded our deliberation of this matter on January 6, 2003.

B. Background

The history of the issue of hedging with financial derivatives for NU pre-dates the Company's filing in this docket. Due to increasing volatility in the price of natural gas over the past several years, both the industry and the regulatory community have focused on financial derivatives as a possible tool to moderate large price swings like those experienced in recent winters. In December 2000, the Commission directed NU:

> …to comment on the possibility of … implementing price hedging mechanisms, or other options that would assist customers to mitigate the effects of the volatility of the gas markets ….

See *Northern Utilities, Inc., Proposed Cost of Gas Factor for the 2000/2001 Winter Period - Mid-Course Correction,* Docket No. 2000-680, Order (Dec. 28, 2000) at 3.

The Company filed a written response in which it reported that it maintained significant price diversity within its portfolio.

> Northern is able to temper price volatility by utilizing underground storage and peaking resources while allowing its sales customers some flexibility to participate in the potential downside of the market. While Northern has considered the use of financial instruments to hedge gas supplies in the past, it chose instead to develop a resource portfolio that accomplishes hedging primarily through the use of physical assets.

See NU Response, Docket No. 2000-680, dated January 18, 2001 at 1-2. NU indicated it would continue to explore hedging with financial derivatives as a supplemental means of mitigating future price volatility.

NU also noted that the New Hampshire PUC staff wanted it to employ financial derivatives and to provide a fixed price option (FPO) for New Hampshire gas consumers. Because the Company manages its gas supply portfolio to meet the needs of customers in both states, NU proposed a meeting with Staffs of both the Maine and New Hampshire PUCs to discuss hedging possibilities and FPOs. At a meeting on February 16, 2001, in support of its view that the use of derivatives-based hedging was unnecessary for NU, the Company stated that the large amount of storage gas in its portfolio gave its ratepayers greater protection from winter market price fluctuations than was available for other LDCs in New England.

In May 2001, however, NU contacted Maine PUC Staff, indicating that it was imminently preparing to execute a financial hedge, and asked how the Commission would view such an action. In informal discussions between May and July 2001, Staff indicated that, without an approved hedging policy that specified otherwise, NU's use or non-use of financial derivatives as hedging instruments would be evaluated in the same manner as any of the Company's management or gas procurement decisions when determining whether associated costs would be allowed in rates. The Company was told that it should act prudently in securing necessary gas supplies whether or not that required the use of financial derivatives.

Later, as Northern prepared to engage in hedging activity to allow it to offer an FPO to its New Hampshire gas customers, NU initially indicated that, because Maine and New Hampshire "share" a gas supply portfolio, it would be necessary, or at least preferable, to hedge for Maine when it did so for New Hampshire. However, after the discussions with Staff in May and July 2001, NU indicated that it is unwilling to hedge with derivatives on behalf of Maine consumers without prior approval by the Commission in order to avoid any adverse regulatory consequences or "second guessing" of its hedging decisions. Meanwhile, the Company developed an FPO for its New Hampshire division with the support of the NH PUC Staff and used derivatives to hedge the supply necessary to cover that offering for the winter of 2001-2002.

On August 15, 2001, in Docket No. 2001-572, NU filed its proposed CGF for the Maine division showing that its procurement strategy for Maine for the winter 2001-2002 period excluded the use of financial derivatives.

In its Supplemental Order in that docket dated November 13, 2001, the Commission, in addressing NU's decision not to use derivatives for hedging purposes for the 2001-2002 winter period, noted on page 6:

> Ultimately, it is within our regulatory purview, provided there are adequate supporting facts, to find Northern imprudent if it has not used financial hedging instruments in its gas procurement when it would have been sound business practice to do so. However, we can assure Northern (and its parent, NiSource) that we seek to be fair in our assessment of managerial decisions and would not "second guess" or discount Company decisions with the benefit of hindsight if reasonable when made. Rather, in the absence of clearer

> guidelines, we would review hedging decisions with precisely the same regulatory treatment as other contracts related to gas procurement or any other aspect of the utility business. In this regard, a decision to hedge is, in principle, no more likely to be judged imprudent as a decision not to hedge.

C. Legal Authority

Title 35-A of the Maine Revised Statutes Annotated (M.R.S.A.) § 4703 and Chapter 430 of the Commission's Rules require gas utilities to file cost of gas adjustments for Commission approval and establish various legal requirements for such adjustments. Section 1(D) of Chapter 430 defines what constitutes a cost of gas for inclusion in the cost of gas adjustment mechanism as follows:

> … the total charges paid by the gas utility for gas received into system supply for sale to its customers, less any cash or other discounts, and less any supplier refunds to be credited …[and] associated costs including, but not limited to labor, carrying costs, or the cost of handling the gas prior to its delivery to the gas utility for sale to its customers. The cost of gas shall also include any back out charges, pay out charges, take-or-pay charges (sic) have been prudently incurred. The cost of gas shall not include demurrage, purchasing agent commissions, on-system storage costs, or other non gas-related expenses incurred on system by the gas utility.

Finally, Section 4706(8) allows the Commission, when implementing an alternative ratemaking mechanism, to "waive or modify the requirements of section 4703 to the extent necessary to promote efficiency, appropriate financial incentives, rate stability or equitable cost recovery."

D. Record

The record of this proceeding shall consist of all transcripts and documents (including data requests and responses) filed with the Commission.

III. REVISED HEDGING PROGRAM DESCRIPTION

Consistent with its original plan, NU's revised proposal relies exclusively on futures contracts and cites rate stabilization as its primary goal. As a secondary goal, NU constructed its program to be uncomplicated and mechanically applied, thus enabling the Commission and other interested parties to more easily become familiar with the use of derivatives as hedging tools. NU noted that cost minimization is neither a primary nor a secondary goal of its program and likened the costs incurred in trading derivatives to "insurance premiums."

The most notable differences between the original and revised proposals are in the gas volumes to be hedged, and in the particular months that will be hedged. In NU's original proposal, it appeared that the Company wanted to hedge up to 60% of its supply on a year-round (12-month) basis. Currently, NU proposes to hedge (through the use of derivatives) between 15% and 26% of supply for eight months each year, including May and October through April. An additional 63% of supply in these targeted months would be effectively hedged by storage quantities of natural gas, liquefied natural gas (LNG) and liquefied propane (LP) purchased in quantities and at prices completely at the Company's discretion. Therefore, in the target months, a minimum of 78% (63%+15%) to a maximum of 89% (63%+26%) of total forecasted volume would be hedged through a combination of storage and the use of futures contracts.[2]

NU's plan includes what the Company refers to as "Non-Discretionary" and "Discretionary" components. However, because NU would exercise only limited discretion for both components, it would be more accurate to call these plan components "Time-Triggered" hedges and "Price-Triggered" hedges respectively and henceforth we will refer to them as such. The Time-Triggered component will apply to the 37% of the Company's forecasted supply that is not hedged by storage, for the target months May and October through April. NU will purchase futures contracts covering 40% of the forecasted volumes not covered by storage for the target months over a 12-month time frame in a dollar-cost-averaging scheme.[3]

Due to the operation of Maine's CGF process, the time frame for the purchase of futures contracts will differ for some of the target months. Because May and October fall within "summer" months for gas cost purposes, rate adjustments for those months are filed in February and finalized during March and April. The Company would therefore purchase futures contracts for May and October 2003 during a period between April 2002 and March 2003. Because November through April fall in the winter gas period and the Company files for its winter rate adjustment in August, it would purchase futures contracts for November 2003 through April 2004 over a 12-month period between September 2002 and August 2003. In the August 30 telephone conference, Company witness DaFonte stated that with regard to Time-Triggered hedges, the current corporate practice is to purchase futures contracts on the third business day

[2] The way NU purchases gas for storage is not the subject of this Order.

[3] The 40% Time-Triggered hedge equates to roughly 15% of total volume for the target months (37% non-storage quantities x 40% hedge = 14.8%).

prior to the end of a particular month and he expected to handle such purchases similarly for Maine upon implementation of a plan.

One element of the Time-Triggered component requires discretion. When purchasing futures contracts, the standard quantity for each contract is 10,000 MMbtu, and because NU plans to spread its futures contract purchases out evenly over 12 months, the only way this can be accomplished is if the hedge volumes for each target month are equal to 120,000 MMbtu or a multiple thereof.[4] According to the volume forecasts supplied by the Company, this is not the case in the months of February and March (projected hedge volumes of 160,000 MMbtu each) or in April and May (projected hedge volumes of 200,000 MMbtu each).[5] Therefore, if NU wished to hedge the month of February 2003 over twelve months (from September 2001 through August 2002), and 16 contracts were required, the Company would have had to purchase one contract in eight of twelve months and two contracts in the remaining four months to arrive at a hedged quantity of 160,000 MMbtu. Likewise, in April 2003 when 200,000 MMbtu would require coverage with 20 contracts (again purchased between September 2001 and August 2002), the Company would have purchased one contract in four of twelve months and two contracts in each of the eight remaining months.

In its recent filings, the Company has not specified when in the 12-month buying cycle it would purchase the "extra" necessary contracts. When questioned on this matter in the August 30 telephone conference, NU witness DaFonte stated that it was not the Company's intent that it would be using discretion for such purchases, but rather that extra contracts would be purchased "mechanically" and that "a regular buying pattern would emerge" and be repeated. We accept that this aspect of the plan will not fit into a completely mechanical buying regime and that purchase of the "extra" contracts will necessarily involve the Company's discretion. Nevertheless, we grant the Company prudence protection for the exercise of this element of the plan as well.

The Price-Triggered hedges apply only to the 37% of the Company's supply that is not covered by storage. NU has proposed price triggers at $2.99, $2.46 and $2.24 per MMbtu based on a study of historical prices by Risk Management Inc. (RMI), an independent consultant retained by NU. RMI's price study covers the last four years for the target months, is adjusted for inflation using the Producer Price Index (PPI) and

[4] We note that NYMEX has recently launched a natural gas product it calls "e-miNY's" which trades in a 4,000 MMbtu increment. However, this product has yet to gain wide acceptance, and we could only find a price for the month-ahead contract. Therefore it does not appear that e-miNY's are viable for NU's purposes at this time.

[5] These volumes represent 40% of projected volumes for Maine and New Hampshire combined. The Company stated that projected Maine and New Hampshire volumes are equal but only the New Hampshire figures are shown in Attachment C, page 1 to NU's August 21, 2002 filing.

places a heavier weighting on prices from the most recent year. The resulting price matrix is shown below:

Table 1

Adjusted Quadrant:		
	4th Quadrant	**3.47 – 8.75**
	3rd Quadrant	**2.69 – 3.47**
	2nd Quadrant	**2.32 – 2.69**
	1st Quadrant	**1.76 – 2.32**
Deciles:	**100%**	**8.75**
	90%	**5.24**
	80%	**4.58**
	70%	**3.13**
	60%	**2.85**
	50%	**2.69**
	40%	**2.54**
	30%	**2.37**
	20%	**2.24**
	10%	**2.03**
	Mean	**3.23**
	Median	**2.69**

RMI's matrix shows that the range of NYMEX average closing prices for the target months over the past four years has been $1.76/MMbtu to $8.75/MMbtu with a median of $2.69/MMbtu. NU proposes for the time being that the price trigger points be set at the 65th, 35th and 20th percentiles, which occur at $2.99/MMbtu, $2.46/MMbtu and $2.24/MMbtu respectively. Selection of these particular percentiles as the Price Triggered hedge points appears to be based on the Company's judgment (as well as that of RMI) that historical prices, and the tendency of those prices to regress to mean levels, are meaningful predictors for the future. RMI stated that "[s]tatistical evidence strongly supports the fact that natural gas prices exhibit mean reversion tendencies," however neither they nor NU provided that statistical evidence. Advisory Staff reviewed historical natural gas prices at NYMEX and at the Henry Hub and generally concurs with the historical ranges RMI provided NU. That review did not, however, attempt to confirm or draw any conclusions about the mean reversion tendencies of natural gas.

At each of the specified price triggers, the Company proposes to hedge an additional 10% of the non-storage quantities. Therefore, if at any time the futures price for one of the target months (May, October through April) hits $2.99, NU will purchase futures contracts representing 10% of the non-storage volume (10% x 37% non-storage quantity = 3.7% total volume) for that month.[6] This process will be repeated at price levels of $2.46 and $2.24 per MMbtu. If all three triggers were reached for any of the target months, a total of 11.1% (3 x 3.7%) in additional volumes would be hedged through this mechanism for that particular month. At the volume levels projected by the Company, the potential mismatch that occurs with Time-Triggered hedges due to the 10,000 MMbtu standard contract size does not arise for the Price-Triggered hedges. If the volume projections change in the future, however, this may become an issue.

As was the case in its original filing, NU proposes that all transaction costs, including trading gains or losses, associated with the necessary futures contracts be pre-approved as "prudent" and passed on to ratepayers in full in the Company's semi-annual Cost of Gas (CGF) filings. Therefore, ratepayers would be responsible for the cost of futures contracts, including all gains and losses, covering a minimum 15% up to a maximum of 26% of projected gas supply for the eight target months. NU proposed filing a one-year operating plan each year with its August CGF filing that would detail that year's expected hedging activities, including its volume forecasts. The Company noted in the August 22 teleconference that it may propose re-setting the price points for the Price-Triggered portion of the plan in its semi-annual gas rate filings, and also stated that it would not seek to reset the price points between those filings. We note that in requesting approval of the current plan, NU stated that it is requesting pre-approval, or prudence protection, for the price points ($2.99, $2.46 and $2.24 per MMbtu) for the Price-Triggered component of the plan and would seek similar approvals for each proposed change in these price points in the future.

The Company does not seek to recover the administrative costs (e.g. payroll & benefits of necessary staff) of the program, which it characterizes as negligible, in gas rates. It instead proposes including these costs in base rates through Management Service Agreement (MSA) charges from its affiliates Bay State Gas and NiSource. Management of NU's gas portfolio will continue to be administered by Bay State Gas,

[6] RMI's letter states that futures contracts or options will be used out to a period of 12 months in advance for the Price-Triggered component of the plan. Mr. DaFonte's testimony states that only futures contracts will be utilized and does not mention a 12-month forward limitation. In its Exceptions, the Company clarified its position stating that it would only look 12 months into the future regarding the Price-Triggered element of its plan. We interpret this to mean that if in January 2003 NU observed a $2.99/MMbtu futures price for January or February 2004 (13 or 14 months into the future), it would not make purchases for those months. If, however, the $2.99 price is observed for December 2003 (12 months into the future), NU would make the appropriate 10% purchase assuming that the price trigger had not been reached and acted upon previously.

but the Corporate Gas Supply department of NiSource, Inc. will execute the actual purchase of futures contracts.[7] Trades will be made in accordance with quantity and timing parameters determined by NU, consistent with the plan as filed or subsequently modified. Mr. DaFonte's testimony noted that NiSource has operated a derivatives-based hedging program for another affiliate (Northern Indiana Public Service Company or "NIPSCO") since 1996. NiSource has also adopted a Corporate Hedging Policy (a copy of which was filed with Mr. DaFonte's testimony) and appointed a Risk Management Committee comprising nine senior NiSource executives to oversee trading activities. There are various internal checks and balances in place between NiSource's Trading Operations, Accounting and Treasury Departments, which are used to monitor trading activities to ensure compliance.

In summary, NU is requesting that the Commission approve: (1) the use of futures contracts to hedge 40% (which is equivalent to 15% of total) of the non-storage gas volumes on a Time-Triggered basis; (2) the use of futures contracts to hedge up to an additional 30% (which is equivalent to an additional 11% of total) of the non-storage gas volumes on a Price-Triggered basis; (3) price triggers of $2.99, $2.46 and $2.24 per MMbtu for the Price-Triggered portion of the plan; (4) passing administrative costs of the plan through to ratepayers in base rates; and (5) passing trading costs and gains and losses on futures contracts through to ratepayers in gas rates.

Advisory Staff's discussions with the Company have clarified another important point, that being the standard of review that will be used to determine whether or not hedging costs are deemed prudent and thus recoverable in rates. Quoting from Staff's September 20, 2002 letter to NU:

> …it is Staff's understanding that Northern is only willing to voluntarily accept a hedging mechanism under which all hedging transactions would be triggered by the mechanical application of buying rules that would be fully specified in a hedging program approved by the Commission. This is because to undertake any hedging activities for NU's Maine Division, the Company requires assurance that all hedging activity costs will be recovered from ratepayers. Regulatory prudence review of the Company's hedging activities will be appropriate, in the Company's view, only as to the question of whether the Company acted in accordance with the approved plan and, if not, in the evaluation of whether its deviating actions were reasonable.

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[7] In an Order dated July 2, 2002 in Docket No. 2002-21, *Northern Utilities, Inc., Request for Approval of Affiliated Interest Transaction with NiSource Corporate Services, Inc*, the Company obtained the necessary Commission approval for an affiliate contract with NiSource pursuant to 35-A M.R.S.A § 707.

In the Company's letter dated October 4, 2002, Joseph A. Ferro responded affirmatively but asked that we characterize its position regarding recoverability of hedging activity costs as follows:

> …Northern is seeking assurance that all costs associated with prudent hedging activities undertaken in a manner consistent with the approved hedging plan will be recoverable.

The degree to which the hedging activities are designed to occur under pre-specified parameters in this plan -- essentially the purchase of futures contracts for equal quantities on a particular date each month plus a potential additional portion if futures prices drop to certain historic levels -- allows for virtually no exercise of discretion by the Company. Accordingly, under this plan as proposed, review of the Company's actions for consistency with the plan and, presumably, its competence in carrying out the hedging activities, appear to be the only aspects of the Company's hedging activity amenable to regulatory oversight.[8] There is no provision in the plan for adapting to or taking advantage of changing market conditions though Northern indicated that it might propose modifications in the plan.

As a final note, in the August 22 teleconference, the Company stated its preference that Maine either adopt the plan as proposed, which has since been approved by the New Hampshire PUC, or that there be no hedging for Maine. NU reasoned that the accounting would be more complicated and prone to errors in assigning costs to the proper jurisdiction if Maine did not participate in this plan or if Maine opted for a different hedging plan. Moreover, excluding Maine from NU's hedging program would roughly halve its trading volumes and this could also cause some difficulty in the efficiency of execution of the plan given the 10,000 MMbtu standard contract size.

IV. ANALYSIS

A. Staff's Financial Analysis of Proposed Hedging Plan

The Advisory Staff's analysis of the Company's plan provides a rough comparison of the prices NU would have obtained using futures contracts over the past five winter seasons (plus May and October) to the prices the Company would have paid for spot natural gas covering the same period. We say that it is a *rough* comparison because Staff had to make several simplifying assumptions regarding the timing of purchases and volumes, which will affect the final results. First, it was not possible for

[8] The only possible exception would be for any discretion exercised by the Company in evaluating how and when it will purchase those quantities that do not fit within the standard contract size.

the Staff to definitively re-create the price triggers that would have been in effect for the Price-Triggered portion of the plan for prior years. Therefore, the impact of the Price-Triggered component could not be calculated or even estimated for the 1997-98, 1998-99 or for 1999-2000 hedge periods. For the 2000-01 and 2001-02 hedge periods, Staff estimated the price triggers and compared them to actual futures prices and found that the price triggers would likely not have been reached in 2000-01 and that a small amount of Price-Triggered hedging may have occurred in 2001-02.[9]

Also, as noted previously, futures contracts must be purchased in 10,000 MMbtu increments and, at the Company's projected volumes, this does not occur in February, March, April and May. Because the Company did not state when the extra contracts would be purchased, Staff chose to smooth the purchases over 12 months rather than to arbitrarily select months when two contracts would be purchased rather than one. Using April as an example, smoothing 200,000 MMbtu over a 12-month buying period results in a 16,667 MMbtu being hedged per month when in actuality it would be necessary to purchase one contract in four months (10,000 MMbtu each) and two contracts in the other eight months (20,000 MMbtu each). As the Company did in its presentation of the plan, Staff also assumed that the forecast volumes for each month stayed constant across the years. That is, Staff used the same volume forecast for May 1997 as for May 2002.

Based on the August 30 teleconference with the Company, the Staff's analysis assumed that futures contracts would be purchased on the last day of each month of the buying period. Staff used futures prices as published in the *Wall Street Journal* (WSJ) for calculating the dollar cost for each purchase.[10] To estimate the cost of a like volume of gas on the spot market, Staff used a data series provided by an on-line service, OilEnergy.com. This series shows the daily closing prices for spot gas at the Henry Hub from January 1, 1997 through August 29, 2002. To determine the dollar cost of spot market gas for each month, Staff assumed that it was purchased daily in equal amounts throughout the month, and thus, the spot market cost of gas each month is simply the product of the monthly forecasted volume of gas and the simple average monthly spot price.

Staff's analysis showed that if the Company's plan had been in place for each of the five most recent hedge periods, price volatility would have been somewhat reduced, and on a cumulative basis the Company's plan would have saved customers a small amount over the 5-year period. The following graph and table illustrate the relative price patterns over time. To avoid any misunderstanding, the gas prices shown

[9] If the plan had been in effect for the period covering May 2002 and October 2002 to April 2003, we believe price triggers would have been reached for volumes amounting to just under half of the Price-Triggered hedge target.

[10] Prices for the last day of each month are published in the *WSJ* on the first weekday of the next month. Staff compiled copies of those pages dating back to May 1, 1996.

below are not the prices customers would pay for the entire gas portfolio because the majority of NU's winter gas comes from storage. Instead these prices represent only the price of like volumes of gas under either a hedged or a spot price scenario. To calculate the annual cost per residential customer, Staff used average residential customer counts from NU's annual reports. Note that in Table 2 Staff also calculated that the "hedged price" for the current winter season (including May 2002) is approximately $3.27 per MMbtu.

Graph 1

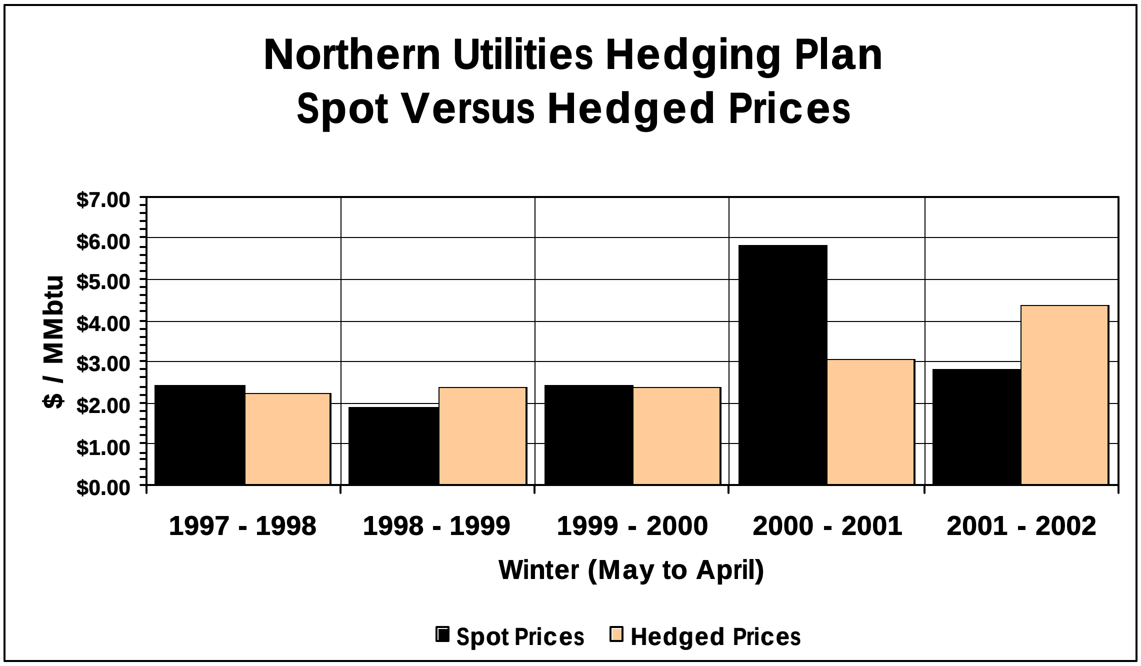


Table 2

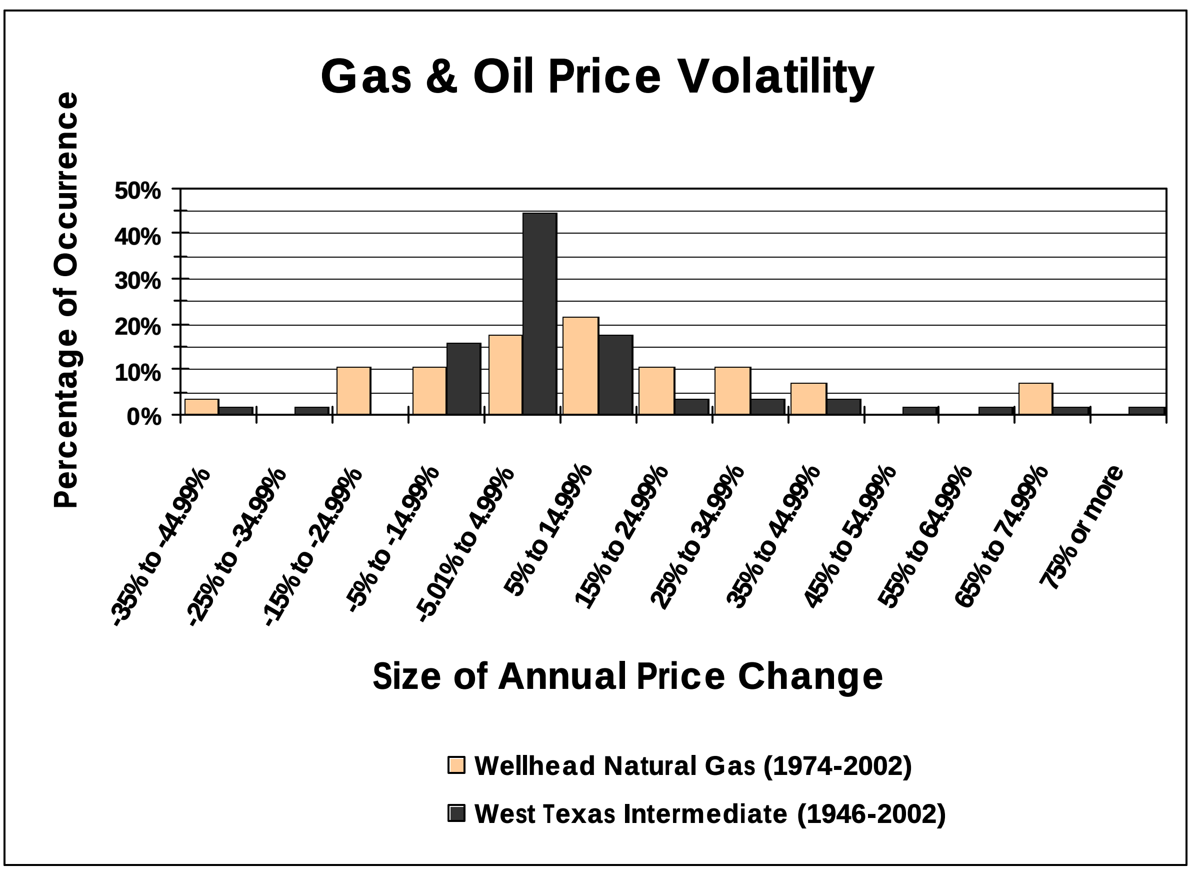
Hedge Period	Spot Price $/MMbtu	Annual % Change	Hedged Price $/MMbtu	Annual % Change	Annual Cost/(Benefit) per Res. Customer
1997-98	$2.42		$2.21		($10.15)
1998-99	$1.92	(21%)	$2.39	8%	$21.04
1999-2000	$2.44	27%	$2.36	(1%)	($3.46)
2000-01	$5.85	140%	$3.04	29%	($121.10)
2001-02	$2.81	(52%)	$4.38	44%	$68.90
2002-03	?	?	$3.27	(25%)	?

Graph 1 and Table 2 appear to indicate that on a year-to-year and a cumulative basis a plan like the one proposed would have provided some level of benefit to ratepayers. As a note of caution, however, these calculations are an approximation and this 5-year look is a relatively short-range test of the plan. It is possible that if Staff had been able to look at this plan over a longer time horizon, a reduction in volatility (the primary benefit claimed by NU) may have been more than offset by the costs of the program. This is because using derivatives to hedge entails costs that are not unlike insurance premiums and insurance policies are not expected to pay off on a regular basis. It is therefore worthwhile to attempt to determine the likelihood that this type of an "insurance policy" will have a pay-off. Staff therefore constructed a probability distribution that examines year-to-year price changes for natural gas and for crude oil. Staff looked at crude oil, because it is possible that there is some correlation in gas and oil price movements and because oil prices have been unregulated for a longer period of time than those of gas.

B. Historical Probability Distributions for Natural Gas & Oil

The Energy Information Administration (EIA) publishes monthly and annual price data for natural gas and certain oil products over long periods of time. The data series for Wellhead Natural Gas covered 1974 to mid-2002, a period of 29 years. The price history for crude oil (specifically West Texas Intermediate or "WTI") dated back 57 years to 1946. For natural gas, the largest annual price increase was 69% (in 2000) and the largest annual decrease was 37% (2002 year-to-date). For WTI, the largest annual increase was 168% (in 1974 during the Arab Oil Embargo) and the largest annual decrease was 42% (in 1986). Overall, the annual price changes for both gas and oil tended to be clustered between –5% and 15%. On a cumulative basis, the annual price change for natural gas was less than 15% for 18 of 28 observations, or 64% of the time. For WTI, the annual price change was less than 15% in 46 of 56 observations, or 82% of the time. The distribution is illustrated in Graph 2 below:

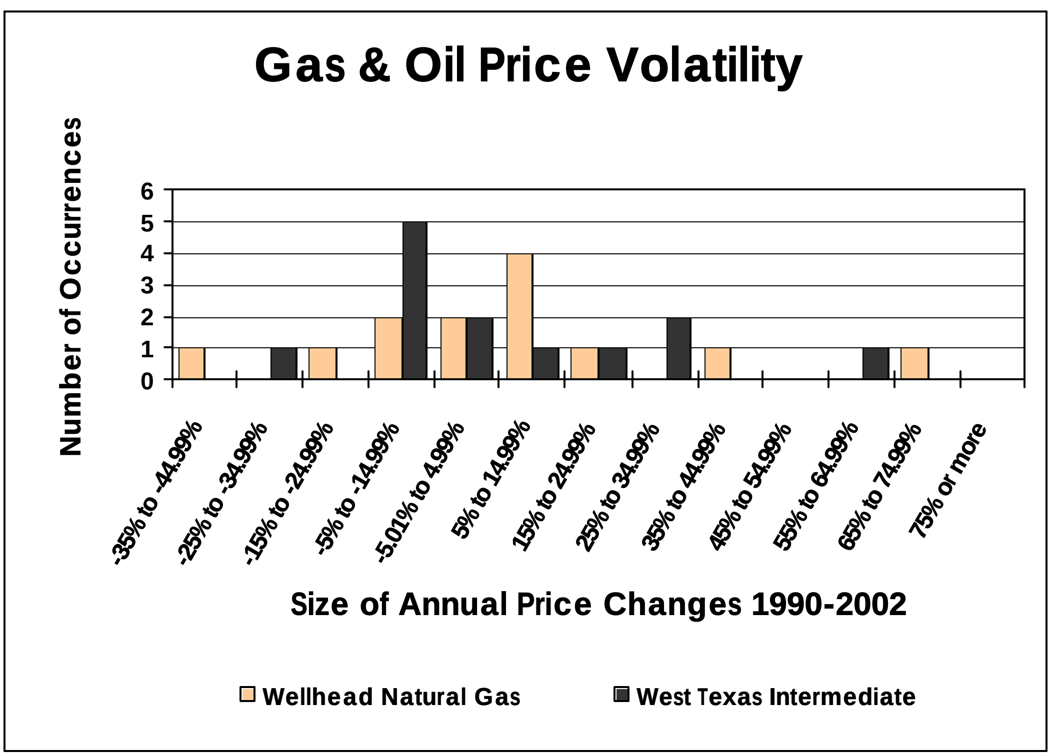
Graph 2



This indicates that very large one-year increases in price for these commodities are somewhat atypical. As discussed in the May 31, 2002 Examiner's Report in this docket, the type of insurance policy that NU proposes here, one based exclusively on futures contracts, locks in prices and does not allow ratepayers to participate in downward price movements and the majority of price movements over the years are either downward or moderately upward (if one considers a 15% increase to be within the "moderate" range). Presumably, ratepayers will only be adverse to price volatility that is upward in direction. If we look back at Table 2, we note that the weighted average spot price for gas during the 1999-2000 hedge period, increased by 27% from the 1998-1999 hedge period. At that level of increase, our calculations show NU's proposed hedging plan would have saved the average residential customer $3.46 over a 12-month period, which is a rather modest amount. However, in a hedge period like the one that occurred 2000-2001, the savings can be much greater ($121.10 annually for the average residential customer). Therefore, it seems that a futures-based hedge plan is more beneficial to ratepayers in an environment where large price increases tend to prevail.

To test the possibility that the price histories Staff examined may be biased towards more stable levels by virtue of their length, Staff reviewed a more recent segment of history for both gas and oil. The results are shown in Graph 3 below which covered the most recent 13 years, 1990 to 2002 (with 2002 being a partial year). Our results for this historical segment are similar in that there were relatively few year-to-year price increases larger than 15%. On a cumulative basis, the annual price change for natural gas was less than 15% for 10 of 13 observations, or 77% of the time. For WTI, the annual price change was less than 15% in 9 of 13 observations, or 69% of the time.

Graph 3



C. Alternative Approach

Based on the record in this case, we can find that Northern's plan will add costs but may yield limited benefits in some measure of price stability and possibly in net savings on gas costs to ratepayers. However, the evidence also suggests that other financial vehicles (e.g. call options) might yield greater benefits at lower total cost. The price histories examined by the Advisory Staff did not show price swings in the 25% to 35% magnitude to be common either in the long run or in more recent years. The Company stated in the August 15 and August 22 teleconferences that if Maine preferred a derivatives-based hedging plan that differed from the one proposed, which it has recently started to implement in New Hampshire, it would rather not hedge Maine's gas supply at all.

NU's October 4, 2002 letter appears to confirm that a truly discretionary element to the plan to allow it to take advantage of changes in market conditions that would work to ratepayers' advantage, something we specifically referenced at our June 25, 2002 Deliberative session, is something the Company is unwilling to voluntarily accept.

We recognize that we cannot perfectly reconcile acceptance of this plan with our previously expressed desire to have Northern monitor market conditions and take alternative action if appropriate without prior Commission approval in the event it sees opportunities to increase benefits to ratepayers or if a rigid application of this plan appears not to work to ratepayers' advantage. We make clear that we do not expect Northern to make unilateral changes to its plan or its hedging activities from those specified in this plan based on market changes. Further, we will not judge its actions with an expectation of flexibility or on the basis of retrospective review of market conditions. However, we do expect the Company to seek modification of the plan if it perceives future benefits from doing so. Specifically, Northern's hedging actions under this plan will be considered prudent so long as it can demonstrate that it: 1) has monitored the market and the actions of other market players including its affiliates; 2) has periodically reviewed the goals of the hedging program and its success in achieving those goals; and 3) has recommended to the Commission changes in the operation of the program whenever the Company has concluded, based on its monitoring of the market and its review of its program, that such changes are warranted. Therefore, if NU fails to come to the Commission to propose a change in the plan once it has determined that it would be wise to do so, we could then find that the Company has acted unreasonably in carrying out hedging activities under this plan.

The challenge here is to reconcile the Company's reluctance to be at risk for making changes in its hedging program, given the inherent unpredictability of commodity markets, and the danger that according prudence protection to a very specific plan could motivate the Company to adhere to the plan even if it concludes that an alternative approach would be more advantageous to ratepayers. Thus, rather than putting the Company at risk for changing or failing to change its hedging strategy on its own, we adopt the middle ground of requiring that it monitor the market and the effectiveness of its hedging program and propose changes to us whenever it deems they are warranted by changed market conditions or other factors. We recognize that to the extent that imprudence, as defined here, constitutes the failure of the Company to act in accordance with its own views, it is a somewhat subjective standard rather than an objective test. While that might limit its usefulness in judging the Company's actions, we note that we would not depend exclusively on statements by Company officials in determining its views of the market, as we would be able to examine other gas purchasing decisions by those responsible for Northern's hedging program to ascertain whether their assessment of the market had changed.

Additionally, we direct Northern to explore other alternatives that may improve the overall effectiveness (or cost effectiveness) of its hedging activities. For instance, because of the actual historical pattern of energy price volatility, where large year-to-year price increases occur infrequently, it may be worthwhile to consider an alternative hedging approach that uses call options to cap prices at some level, perhaps 35% to 40% higher than some previous periods prices. Call options allow buyers the option to purchase gas at a certain price, but do not obligate them to do so. Therefore, a buyer can mitigate upward price spikes without locking itself out of the potential benefit of downward price movements in the gas supply market. This is a marked difference between the use of call options and futures.

As is the case with the futures market, the options market is quite liquid and pricing is transparent. It is true that call options have a greater up-front cost to the buyer than do futures contracts. The up-front cost of an option is known in the industry as the "option premium." The size of the premium is typically a function of four variables: (1) the distance between the "strike" price (i.e. the price at which the option can be exercised) and the price of the underlying commodity; (2) the length of time to expiration; (3) the overall volatility of the underlying commodity, and; (4) current interest rates. The first variable, distance between the strike price and the spot price, is a major factor in the size of the option premium. If the strike price were relatively high compared to the spot price of the commodity, this would require the buyer to pay a smaller option premium. For instance, when spot gas is trading at $4.00 per MMbtu, and the other three variables are held constant, the cost of a call option with a $6.50 strike price would be markedly lower than the cost of a call option with a $4.75 strike price.[11] Therefore, it may be possible that hedging with call options with sufficiently high strike prices could prove to be a more cost effective hedging strategy, which would be better for ratepayers. In contrast with future purchases at set prices and volumes, this strategy

[11] The second major variable is the length of time to expiration of the option. With other variables held constant, a greater length of time to expiration raises the premium. The third variable is the underlying volatility of the spot price of the commodity. Greater volatility increases the probability of the option being exercised and thus causes the premium to be higher than it would be if volatility were lower. Interest rates represent the opportunity cost of capital to the investor. Higher interest rates would make options buyers pay less for options due to the higher opportunity cost they would face.

could give ratepayers up-side price protection without locking them into high prices if the market declines. Given historical oil and natural gas market trends, the use of call options as generally outlined above may be a preferable tool for maintaining price stability (by avoiding large price spikes) than simple time averaging through the ongoing purchase of futures.

Consequently, while we adopt Northern's current proposal, we also direct the Company to work with Staff to evaluate whether additional benefits, either through lower cost or additional price stability, may be gained through the use of call options with relatively high strike prices, either in place of, or in addition to, the current plan.

V. CONCLUSION

For the reasons stated above, we approve Northern's proposed plan as clarified herein but make explicit Northern's obligation to propose modifications when it believes they would benefit ratepayers, and to actively explore alternatives such as the use of call options that might yield an adequate degree of stability with greater cost-effectiveness.

We note that while the Company's proposal probably will reduce price volatility somewhat, the effect will not be substantial unless sudden and severe price increases occur. Given that Northern has a strong dollar-cost-averaging physical hedge strategy in its procurement of storage gas (nearly 63% of its portfolio), it is not clear that this program will yield more than a minor stabilizing benefit to ratepayers. However, Northern has represented that it is proposing this plan as a first step toward a more sophisticated plan. We find that it is an acceptable starting point in the use of financial instruments to procure gas supply.

There are several implementation issues that must be addressed regarding both the Time-Triggered and Price-Triggered elements of the plan because the "buying periods" for futures contracts for the next winter season have already begun. We must also address the specific requests of the Company regarding treatment of administrative and transaction costs of the plan, hedge percentages, the price points requested for the Price-Triggered portion of the plan, and any additional conditions or reporting requirements.

A. Implementation and Timing

With respect to implementation of the plan, it would seem that the Price-Triggered component could be put into effect immediately for all target months with the clarification noted by the Company in its Exceptions addressed previously in footnote 6. We would also re-examine the price trigger points in the Company's summer CGF filing due in February 2003 if changes are proposed by the Company.

Implementing the Time-Triggered portion of the plan is somewhat more complicated at this point in time. We find it reasonable for NU to get started on a "catch-up" basis for November 2003 through April 2004, while ignoring the current winter period and May and October 2003. Accordingly, we direct the Company to do so. For November 2003 through April 2004 there will be eight buying months (ending in August 2003) remaining, assuming the Company starts purchasing futures contracts in January 2003. We do not approve buying futures contracts for the current winter period and for May and October 2003 because doing so would essentially require buying the hedges covering the entire targeted volumes within a very short stretch of time and would run counter to the premise of dollar-cost averaging.

B. Administrative Cost Recovery

Recovering the administrative costs of the hedging program in gas rates is appropriate, under the cost separation methodology adopted in our Order in *Northern Utilities, Inc., Request for Approval of Rate Design and Partial Unbundling,* Docket No. 97-393. We approved a level of administrative costs associated with NU's gas portfolio management function for inclusion in the CGA. Presumably, any hedging administrative costs would be subsumed in that amount. With Chapter 430's exclusion of "purchasing agent commissions," the current rule appears to preclude recovery of commissions associated with arranging hedging transactions in the CGF. However, the rule does not appear to exclude gains and losses associated with the use of financial derivatives for hedging purposes, if the use of financial instruments in gas supply procurement is determined by the Commission to be warranted.

Although the Company did not provide a detailed budget or estimate of the level of those expenses, the incremental cost of administering a hedging program should be relatively small considering that NU/Bay State already maintains a gas supply function, the size of the NiSource organization, and the fact that it already has experience in this area. We expect that these costs can reasonably be subsumed in the existing CGA Administrative cost component. Management labor costs will flow to base rates through affiliate charges under NU's Management Services Agreement with NiSource. Northern did not state any exception to this conclusion in its comments.

Finally, we also allow Northern to include the actual transactions costs associated with purchasing futures contracts or options (along with any gains or losses on the instruments themselves) in the semi-annual cost of gas calculations as suggested by the Company, and to the extent necessary to accomplish this, we waive the provisions of Chapter 430.

C. Hedged Amounts

Regarding hedge percentages for the Time-Triggered and Price-Triggered components of the plan, the Company has not provided any specific evidence or analysis supporting either of the respective targets of 40% or "up to" 30%. However, in this iteration of the plan, the volumes subject to derivatives-based hedging amount to 40% and 30% of the non-storage gas volumes only, and thus equate to roughly 15% and 11% of total volume respectively. We accept Northern's proposed hedging amount because, at 26%, it does not amount to a large percentage of the Company's total gas purchase volumes.

D. Safeguards

The Company reports that NiSource has a detailed risk management policy (a copy of which was filed with NU's petition) with numerous internal checks and balances designed to prevent the unauthorized trading of financial instruments. NU did not indicate whether unauthorized trades have occurred within the NiSource family and, if so, how those transactions were reversed internally and what entities maintained financial responsibility. While we may be stating the obvious, the Company should be aware that negative effects of unauthorized trades would not be allowed in Maine's gas rates.

E. Price Targets

As was the case with the hedge percentages, there also was not a great deal of support for the price targets that the Company proposed for the Price-Triggered portion of the plan. However, neither the methodology nor the actual Price-Triggered price points are particularly objectionable. As noted previously, the Company expects to re-examine the price triggers on at least a semi-annual basis and will request adjustments if it deems them appropriate with its CGF filings. The Commission will be free to re-evaluate both the methodology and the price points themselves at those times.

F. Reports

In his testimony, Mr. DaFonte stated that Northern would receive monthly reports from NiSource that would allow it to monitor its hedging activities. These reports would include the date, quantity, price and transaction costs of any financial instruments purchased. The Staff proposed that NU be required to file these reports with the Commission as they are received, as well as "transaction reports" detailing its activities, and copies of the "buy-orders" or any other transaction requests it places through NiSource on more or less of a real time basis after they are issued.[12] Staff believes that the real-time filing of transaction requests will help us identify unauthorized transactions and will enable the Commission to routinely monitor NU's activities on an on-going basis, which might assist the efficient and timely review of hedging transactions in the semi-annual CGF process. Northern comments that providing real-time transaction reports would be difficult and requests that it instead be permitted to submit a summary of transactions only. We believe that it should be sufficient for Northern to file monthly summaries accompanied by such other detail (such as the actual "buy-orders") as Staff determines, after consulting with Northern, to be useful, at least initially, to assist in our oversight without undue burden to the Company.

[12] Although these reporting requirements specifically refer to NU, we would recommend that they be required of any company using derivatives as part of a hedging program.

In addition, we previously noted the Company's intention to make an "informational " filing each August with its semi-annual CGF filing. While NU should not be discouraged from doing so, the Company should also file a performance report with us annually by January 15, beginning in 2004. In addition to evaluating the plan's performance, we expect this report to include a discussion of whether NU has identified any areas where the plan is lacking and how it plans to address those areas. If the Company envisioned providing such an analysis in its August informational filing, we believe a January filing is more useful than an August filing due to the timing of the purchases of futures contracts, given that the Time-Triggered element of the plan envisions hedging purchases for the November through April winter period being completed by the preceding August. Therefore, if the Company wished to make changes to its plan that would take effect in time for the next winter period, an August filing would be too late if the Commission or other party wanted to explore or challenge the proposed refinements.

G. Section 901 & 902: "Umbrella" Approval of Utility Debt Transactions

There is a last legal matter that must be addressed with respect to the use of financial derivatives. The Commission has previously approved the limited use of financial derivatives, specifically swap contracts, that Bangor Hydro-Electric Company (BHE) entered into pursuant to our approval in *Bangor Hydro-Electric Company, Request for Waiver from 35-A M.R.S.A. Section 902 to Enter Into Oil Price Hedge Agreements,* Docket No. 95-242. We determined in that docket that swap agreements constituted "evidences of indebtedness" pursuant to 35-A M.R.S.A. §901 and to the extent that they had maturities greater than one year would require our approval.[13] We granted BHE the appropriate approvals under 35-A M.R.S.A. §§ 901 & 902 in an "umbrella fashion" so that it could react quickly to market conditions rather than having to make a filing with the Commission and await specific approval.[14] We believe that it is appropriate to allow a similar treatment for LDCs that choose to use derivatives strictly for hedging purposes for the same reason here. The Commission would likely extend this treatment to futures contracts and options on natural gas because they are available with maturities extending beyond one year. For this reason, we allow this treatment for Northern in this instance.

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[13] We also found this to be the case in several interest rate swap agreements entered into by CMP, the most recent of which was *Central Maine Power Company, Application of Interest Rate Swap Transactions,* Docket No. 2000-365.

[14] The Commission cited the "shelf approval" of CMP's medium term note program in *Central Maine Power Company, Application for Approval of Issue of Securities (Medium Term Notes Series A, $150,000,000),* Docket No. 89-232 as precedent.

Accordingly, we

O R D E R

That Northern Utilities, Inc.'s proposed hedging plan is approved for implementation as clarified above.

Dated at Augusta, Maine, this 7th day of January, 2003.

BY ORDER OF THE COMMISSION

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Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.